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Biomass for electricity in the EU-27: Potential demand, CO_2 abatements and breakeven prices for co-firing

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HIGHLIGHTS

- Technical potential of biomass (demand & CO_2 abatement) in European electricity.
- Calculation for co-firing & biomass power plants; comparison with potential biomass supply in EU-27 countries.
- Calculation of biomass and CO_2 breakeven prices for co-firing.
- Potential demand is 8–148% of potential supply (up to 80% of demand from co-firing).
- High potential abatement from co-firing (up to 365 Mt/yr); Profitable co-firing with €16-24 (25–35) biomass price for €20 (50) CO_2 price.

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ABSTRACT

This paper analyses the potential of biomass-based electricity in the EU-27 countries, and interactions with climate policy and the EU ETS. We estimate the potential biomass demand from the existing power plants, and we match our estimates with the potential biomass supply in Europe. Furthermore, we compute the CO2 abatement associated with the co-firing opportunities in European coal plants. We find that the biomass demand from the power sector may be very high compared with potential supply. We also identify that co-firing can produce high volumes of CO_2 abatements, which may be two times larger than that of the coal-to-gas fuel switching. We also compute biomass and CO2 breakeven prices for co-firing. Results indicate that biomass-based electricity remains profitable with high biomass prices, when the carbon price is high: a Euros 16–24 (25–35, respectively) biomass price (per MWh_{prim}) for a Euros 20 (50, respectively) carbon price. Hence, the carbon price appears as an important driver, which can make profitable a high share of the potential biomass demand from the power sector, even with high biomass prices. This aims to gain insights on how biomass market may be impacted by the EU ETS and others climate policies.

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1. Introduction

In adopting the 2001 Directive (2001/77/EC) on the promotion of electricity produced from renewable energy sources, the European Union demonstrated its commitment to renewable energy. This was confirmed in 2008, with the Climate and Energy Package, extending the EU's climate policy beyond 2012. The package includes three targets to be reached by 2020: a 20% reduction in greenhouse gas (GHG) emissions from the 1990 level, 20% of renewable resources in energy consumption, and a 20% increase in energy efficiency.[1]

Biomass is increasingly acknowledged to be one of the main renewable energy sources (RES) for achieving EU targets. The use of biomass would not only increase the proportion of RES, but it would also reduce CO_2 emissions, since biomass is considered to be carbon-neutral.[2] There are also a number of concerns about the sustainability of bioenergy, including potential impacts on food/feed, land-use changes, and reduced biodiversity. While such negative externalities are difficult to eliminate, most of them are

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[1] The Climate and Energy Package, which was first discussed in 2008, entered in force in 2009 through adoption of Directive 2009/28/EC. EU objectives on

(*footnote continued*)
biomass has been further defined in the biofuels Directive (2003/30/EC), and in the Biomass Action Plan of 2005.

[2] See EFC (2010) and DECC-SAP (2011) for discussions about current CO_2 emissions from burning biomass. See also Sjølie and Solberg (2011) and Caurla et al. (2013).

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considerably reduced by using lignocellulosic biomass. Among the positive effects of lignocellulosic biomass is the fact that it does not enter into competition with food (other than indirectly, through land-use) unlike energy crops such as sugar beet or maize. This also reduces concerns about land-use, since a large proportion of feedstocks come from agricultural and forestry residues. Moreover, as with forestry, remaining concerns should be addressed through certifications (ECF, 2010).

Biomass-based electricity is of great interest because it enables RES to be developed with little or no investment, through the co-firing of biomass in coal plants. Given the high percentage of coal in European electricity, co-firing provides great opportunities for increasing the share of renewable electricity in the near-term, through reliable technologies that are not subject to problems of intermittency. With respect to CO_2 emissions, co-firing can be considered as a highly effective abatement measure, because it substitutes biomass, with zero emissions under the European Union Emission Trading Scheme (EU ETS), for coal, which produces the highest CO_2 emissions.[3]

This paper investigates the question of biomass usage in European electricity, and interactions with climate policy and the EU ETS. We estimate the potential biomass demand from existing power plants in the EU-27, we match our estimates with the potential biomass supply, and we derive the CO_2 abatement from co-firing. We also compute biomass and CO_2 breakeven prices for co-firing. To date, very few papers have investigated the question of how much biomass can be used in European electricity. Of these, Berggren et al. (2008) estimate the technical potential for biomass co-firing in Poland. This paper focuses on matching the potential biomass supply in Poland with estimated opportunities for biomass co-firing in existing coal plants. The authors also derive the CO_2 abatements from co-firing. The results indicate that about 4 Mt of CO_2 can be abated each year in Poland through biomass co-firing in coal plants. Hansson et al. (2009) estimate the potential biomass demand from co-firing in existing European coal plants. However, unlike Berggren et al. (2008) for Poland, the authors do not compare their results with the potential biomass supply, nor do they compute the CO_2 abatements from co-firing.

Our paper extends these previous contributions by estimating the potential biomass demand from both co-firing and dedicated biomass power plants in the EU-27. We compare our results with the potential biomass feedstocks in Europe, as given in the literature. This allows us to shed light on how the biomass market may be impacted by biomass demand from electricity. We also compute the CO_2 abatements associated with the co-firing opportunities in the EU-27. Additionally, we provide an original method that enables us to estimate the marginal cost of co-fired electricity and the biomass and CO_2 breakeven prices for co-firing. These values reflect the economic conditions that make co-firing profitable in different types of coal plants. To the best of our knowledge, no previous work has provided such an analysis. This allows us to discuss potential consequences of biomass demand from electricity in terms of competition among different usages for biomass.

Compared to the previous literature, our contribution is threefold. First, we estimate the potential biomass demand from the existing power plants in the European electricity sector, considering both biomass co-firing in coal plants and dedicated biomass power plants. Second, we match our estimates with the potential biomass supply in Europe, and we compute the CO_2 abatements associated with co-firing opportunities in the EU-27. Third, we provide a method that enables us to compute the biomass and CO_2 breakeven prices for co-firing.

The remainder of the paper is organized as follows. In Section 2, we give a brief overview of questions related to biomass-based electricity generation and we introduce the methods for estimating potential biomass demand, CO_2 abatements, and breakeven prices for co-firing. Section 3 presents the estimation results. In Section 4, we match our estimates with the potential biomass supply in Europe, and we discuss how the biomass market may be impacted by biomass demand from the European power sector. Section 5 concludes.

2. Material and methods

We begin this section with a brief overview of the technological options for using biomass in power generation. We also describe the impact of some pre-treatments for biomass. Once this background introduced, we present the methods we used in our estimations.

2.1. Technical options for biomass-based electricity

2.1.1. Combustion in dedicated biomass power plants

Dedicated biomass power plants (*i.e.*, power plants that are specifically designed for biomass) have to be adapted to supply limitations. Accordingly, they are typically smaller than coal plants (1–100 MW, about ten times smaller than coal plants), because local feedstocks are limited and transportation costs are high. The small size greatly increases investment costs and lowers conversion efficiency compared to co-firing in coal plants. In Europe, the investment cost of biomass plants varies from USD 3000–5000/KW, depending on technology and size (IEA, 2007). This is about three to ten times more than the investment cost for retrofitting coal plants for co-firing (excluding the indirect co-firing configuration, which is much more expensive). The investment cost may even reach Euros 9000/KW for CHP plants. In this case, the higher investment costs result in higher overall efficiency of the energy conversion chain. Moreover, some countries have adopted specific support policies for biomass when it is used in CHP plants (EURELECTRIC, 2011).

2.1.2. Biomass co-firing in coal-power stations

Co-firing is the simultaneous combustion of biomass and coal in a coal plant. It is the cheapest option for using biomass in electricity. A wide variety of biomass can be used, including herbaceous and woody materials, wet and dry agricultural residues, and energy crops. Currently, the typical conversion efficiency for a dedicated biomass power plant is 25–30% (Ecofys, 2010), while the average efficiency for conventional coal plants is around 36% in OECD countries, with new state-of-the-art plants reaching at least 43% (Wicks and Keay, 2005). Biomass co-firing is expected to reduce the efficiency of coal plants, due to potential sources of losses associated with biomass (*e.g.*, presence of non-preheated air in biomass, increased moisture content, etc). However, the impact is modest for low levels of biomass co-firing (IEA-IRENA, 2013), and conversion efficiency is higher compared with dedicated biomass plants. Accordingly, biomass co-firing is a promising way to convert biomass into electricity, and it offers one of the best opportunities for reducing GHG emissions from electricity. There are three basic co-firing options:

- *Direct co-firing:* This is the cheapest and simplest co-firing configuration. Biomass and coal are burned in the same boiler. This is by far the most widely applied co-firing configuration, and it enables co-firing percentages of approximately 3–5% on an energy basis, without investment (Al-Mansour and Zuwala, 2010).

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[3] Under Directive 2003/87/EC (establishing the EU ETS and related rules) and Decision 2007/589/EC (establishing guidelines for the monitoring and reporting of greenhouse gas emissions), emissions from burning biomass are exempted from surrendering corresponding allowances. This is equivalent to a zero emission factor applied to biomass.

- *Indirect co-firing:* This is a less common option in which a gasifier converts biomass into a gas that is burned with coal in the same boiler. This approach is more expensive, but it allows a greater variety and higher percentages of biomass to be used.
- *Parallel co-firing:* This consists in installing a separate biomass boiler that supplies the same steam cycle. As with indirect co-firing, this method allows high biomass percentages and greater fuel flexibility, but it requires much more investment than simple direct co-firing.

The investment cost for retrofitting a coal plant for co-firing is in the range of USD 430–500/KW for direct co-firing, USD 760–900/KW for parallel co-firing, and USD 3000–4000/KW for indirect co-firing (IEA-IRENA, 2013). It depends on the plant capacity and service (*i.e.*, power generation only or CHP), the biomass quality, and the existing boiler type. Apart from indirect co-firing, these costs are always significantly lower than the cost of investing in a dedicated biomass power plant.[4]

Co-firing also involves difficulties and constraints that limit the utilization of biomass in coal pants. These limitations include problems of modification of combustion behavior, possible reduction in conversion efficiency, deposit formation (slagging and fouling), corrosion, erosion, and resulting changes in equipment life-time related to the quality of the biomass. For instance, the higher inorganic matter content of herbaceous biomass results in higher potential problems of deposit formation. At present, only moderate biomass levels can be co-fired without significant problems. Nevertheless, many of these difficulties can be overcome through different pre-treatments to improve biomass quality and increase the quantity of biomass that can be included in coal plants. Indeed, the higher the quality of the biomass, the greater the quantity of biomass that can be co-fired in coal plants. The coal plant technology and the co-firing option are also important. Although direct co-firing is the cheapest option, it causes more severe problems than other co-firing configurations. Hence, the co-firing percentage is typically lower with direct co-firing than with other options.

2.1.3. Pre-treatment of raw biomass

Most of the co-firing constraints originate from fuel properties. Raw biomass usually has high moisture content and chemical composition that reduce the efficiency of coal plants and may generate corrosion. Various pre-treatments can be applied to raw biomass to avoid these problems. Pre-treatment can also lower the costs of handling, storage, and transportation, creating new opportunities for long-distance trade. Finally, pre-treatment could reduce the need to invest in expensive co-firing technologies.[5]

Several biomass pre-treatments are available. Basic pre-treatments include drying, chipping, and grinding. More advanced pre-treatment options are pelletisation, torrefaction, and pyrolysis. Pelletisation is a process that densifies fine biomass particles into compact and low-moisture capsules by applying pressure and heat. Torrefaction is a thermo-chemical pre-treatment that consists of heating biomass in the absence of oxygen. Temperatures between 200 and 300 °C are required, which produces a solid uniform product (torrefied biomass) with a very low moisture content and a high energy density. Torrefied biomass contains around 70–90% of the initial weight and 80–90% of the original energy content (Uslu et al., 2008). The remainder is converted into gas, with some losses. Like torrefaction, pyrolysis is a thermo-chemical pre-treatment performed in the absence of oxygen. Temperatures employed in pyrolysis are 400–800 °C, and the products are gaseous, liquid (bio-oil), and solid (biochar).

The cost of pre-treatment may vary significantly from one option to another, but it is usually high.[6] However, it can be offset by better operability of fuel (*e.g.*, handling, storage, and transportation), reduced co-firing constraints, and higher efficiency of coal plants. Recent studies point out that the cost of pre-treatment may represent more than 50% of the overall cost for torrefied wood pellets (KEMA, 2012; IEA-Bioenergy, 2012). However, when taking into account the benefits of pre-treatment on the whole supply chain, up to the point of combustion, torrefied wood pellets may be more profitable than simple wood pellets (IEA-Bioenergy, 2012).[7]

2.1.4. Summary and implications for potential demand

The different technical options described above underline the constraints associated with biomass-base electricity, and how this may affect co-firing and potential biomass demand. In order to better connect this with the estimations in the subsequent sections, we propose a summary of the main effects involved (Table 1).

Table 1 indicates that indirect co-firing allows the highest percentage of biomass incorporation, whatever the quality of biomass (thanks to the gasification of biomass). Direct co-firing produces the lowest percentage of biomass incorporation when associated with no pre-treated biomass, whereas it can reach 50% with intensive pre-treatments of biomass. For parallel co-firing, the quantity of biomass that can be used depends entirely on the capacity of the boiler in which the biomass is burned.

An important distinction for our estimations concerns the scale of the modifications that have to be made to coal plants to enable co-firing. While parallel and indirect co-firing require extensive modifications at costs similar to new investments, direct co-firing necessitates no or only moderate modifications. Thus, it can be implemented in existing coal plants, which is the focus of this paper.[8] Accordingly, we choose to concentrate on direct co-firing in our estimations. In this case, the more intensive the biomass pre-treatment, the higher the incorporation rate and the resulting potential biomass demand.

2.2. Estimation method for potential biomass demand and CO_2 abatement

We propose here a method that enables us to estimate the potential biomass demand and CO_2 abatements from using biomass in the European power sector. These quantities represent technical potentials, which do not necessarily coincide with

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[4] Investment costs for indirect co-firing are about ten times higher than for direct co-firing. However, this configuration allows for the use of cheaper waste fuels with impurities, which can greatly reduce operating costs related to fuel consumption.

[5] For an overview of biomass pre-treatments and economic issues related to co-firing, see Maciejewska et al. (2006), Le Cadre et al. (2011) and Le Cadre (2012).

[6] According to Maciejewska et al. (2006), the cost of pre-treatment varies from 10–20 (chipping/grinding) to around 45–55 (torrefied pellets) Euros per ton of input. IEA-Bioenergy (2012) estimates that the pre-treatment cost accounts for about 4 Euros per GJ for wood pellets (approximately 45% of the final price) and 5 Euros per GJ for torrefied pellets (approximately 55% of the final price).

[7] Uslu et al. (2008) evaluate torrefaction, pyrolysis, and pelletisation in terms of their energy and economic performances on the whole biomass-to-energy supply chain for power generation and biofuel production. Results indicate that torrefaction is more advantageous than pelletisation, while pyrolysis has drawbacks in terms of energy and economic efficiency when compared to other pre-treatments. When torrefaction is combined with pelletisation, this results in the optimal supply chain from an energy and economic perspective.

[8] In practice, almost all the experiences correspond to direct co-firing, and there are currently very few power plants that allow other configurations than direct co-firing (Al-Mansour and Zuwala, 2010).

Table 1
Summary of technical options and implications for the co-firing potential.

	Biomass Pre-Treatment (PT)		
	No PT Wet agricultural residues	Intermediate PT Wood pellets	High PT Torrefied pellets
Co-firing with no or very moderate modifications of coal plants – existing coal plants			
Direct co-firing	– Highest efficiency loss – Lowest incorporation rate (around 5%)	– Moderate efficiency loss – Intermediate incorporation rate (around 20%)	– Efficiency loss tends to zero – High incorporation rate (around 50%)
Co-firing with high modifications of coal plants – new investments			
Parallel co-firing	– No efficiency loss – No incorporation rate (separate boilers)	– No efficiency loss – No incorporation rate (separate boilers)	– No efficiency loss – No incorporation rate (separate boilers)
Indirect co-firing	– No efficiency loss – Highest incorporation rate (more than 50%)	– No efficiency loss – Highest incorporation rate (more than 50%)	– No efficiency loss – Highest incorporation rate (more than 50%)

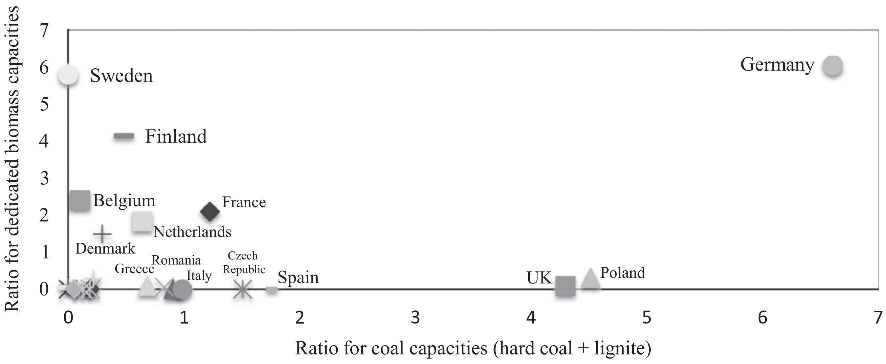

Fig. 1. Installed capacities for coal (hard coal + lignite) and dedicated biomass power plants in the EU countries. Values are ratios between capacities of each country and the EU average capacity. Data provided by ENTSO-E (www.entsoe.eu).

economic optimization. Our aim is to figure out the volumes that are technically attainable, regardless of economic decisions. In addition, our method of estimating the biomass and CO_2 breakeven prices for co-firing (see Section 2.3) reflects economic conditions that make co-firing profitable.

2.2.1. Overview of coal and dedicated biomass capacities in the European power mix

In order to form some initial intuitions about biomass potential in the European power sector, we begin with a short overview of coal and dedicated biomass capacities in EU countries. This is summarized in Fig. 1, which illustrates, for each technology (coal and biomass) in each country in 2011, the ratio between the installed capacity in the country and the EU average installed capacity.[9] Thus, for a given type of power plant (coal or biomass), a ratio higher than one means that the country has more installed capacities than the EU average (and *vice versa*).

Fig. 1 enables us to distinguish between countries with many dedicated biomass and few coal plants (Sweden, Finland), many coal and few dedicated biomass plants (Poland, UK), and both many coal and dedicated biomass plants (Germany).

2.2.2. Estimation method

The method consists in determining the amount of primary energy associated with observed power generation. This enables us to deduce how much biomass can be used in electricity. In the case of coal plants, we derive the volumes of biomass entering the boiler, given a percentage of biomass in the biomass-coal blend (on energy basis). We call this the *incorporation rate*. Once the quantities of coal and biomass are known, we estimate the CO_2 emissions from coal. Emissions are calculated with and without co-firing, enabling us to compute CO_2 abatements. Basically, the method encompasses three steps, which are summarized in Table 2.

In order to figure out a range of values in which to situate the potential biomass demand and CO_2 abatements, we consider two extreme cases, reflecting minimal and maximal values. Thus, we get a lower (*min case*) and a higher (*max case*) range (Table 3).

For incorporation rates and loss coefficients, the values in Table 3 reflect differences induced by variations in biomass quality. The higher the quality of biomass, the higher the incorporation rate is. This translates into higher incorporation rates for ToP than for RAW.[10] Thus, we assume incorporation rates of 5 and 50%, reflecting the *min case* and the *max case*, respectively.[11] Losses on

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[9] For instance, the ratio for coal capacities in Germany corresponds to the German coal capacities divided by the EU average of coal capacities.

[10] Co-firing is currently feasible with incorporation rates of 20%, and sometimes almost 50%. With pre-treatments, incorporation rates can reach more than 50%. However, in practice, actual incorporation rates rarely exceed 10% (IEA-IRENA, 2013). Interested readers can also refer to IEA data-base about co-firing, available at http://www.ieabcc.nl/database/cofiring.php.

[11] Berggren et al. (2008) and Hansson et al. (2009) assumed incorporation rates ranging from 10 to 15%, in order to fit what is most often observed in current practices. By contrast, we assume a large range of incorporation rates, reflecting a wide a range of possible cases from very conservative (5%) to the most prospective (50%) values. Moreover, as opposed to the aforementioned papers, we take into

Table 2
Method for estimation.

Three-step estimation method
Step 1: *Estimating the quantity of primary energy associated with observed production*
$Q_c^i = \frac{Y_c}{\eta_c^i}$ is the quantity of primary energy (MWh_{prim}) in coal plants of type c, with c={*Hard-Coal (HC), Lignite (L)*} and i={*co-firing (cf), no co-firing (nocf)*}. Y_c represents the production of coal plants c (MWh_{elec}), and η_c^i is the efficiency rate of coal plants c under i cycle (MWh_{elec}/MWh_{prim}). Using the same method, we also compute the quantity of primary energy entering in dedicated biomass power plants.
We model the efficiency rate of coal plants under co-firing using the following equation: $\eta_c^{cf} = \eta_c^{nocf} - \rho_b\, inc_{c,b}$, where subscript b denotes the type of biomass. ρ_b is a coefficient measuring possible losses in the efficiency rate of coal plants under co-firing with biomass b, and $inc_{c,b}$ represents the incorporation rate of biomass b in coal plants c.
Step 2: *Estimating the quantity of biomass entering in the boiler, in case of co-firing*
Under co-firing, $Q_c^{cf} = Q_{c,c}^{cf} + Q_{c,b}^{cf}$, where $Q_{c,c}^{cf}$ and $Q_{c,b}^{cf}$ are, respectively, the quantity of coal and the quantity of biomass in the blend. $Q_{c,b}^{cf} = inc_{c,b} Q_c^{cf}$ and $Q_{c,c}^{cf} = (1 - inc_{c,b}) Q_c^{cf}$.
Step 3: *Estimating the CO_2 emissions and associated abatement*
$E_c^i = e_c Q_{c,c}^i$ represents CO_2 emissions of coal plants c under i cycle (tCO_2), where e_c is the primary energy emission factor (tCO_2/MWh_{prim}). In case of co-firing, $Q_c^{nocf} \equiv Q_{c,c}^{nocf}$. Then, we get co-firing abatements as follows: $A_c = E_c^{nocf} - E_c^{cf}$.

Table 3
Lower and higher range for potential biomass demand and CO_2 abatements.

Cases to estimate	Biomass type	Incorporation rate (%)	Losses coefficient
Min case (lower range)	Low quality=Raw biomass (RAW)	5	$\rho_{RAW} = 0.05$
Max case (higher range)	High quality=Torrefied pellet (ToP)	50	$\rho_{ToP} = 0$

coal plant efficiency also depend on the type of biomass. Hence, the value of the loss coefficient increases when the biomass quality decreases. As a limit case, we assume a zero loss coefficient for ToP.

The way we model η_c^{cf} enables us to represent the effect of different incorporation rates on efficiency losses, for a given loss coefficient (Table 2). According to Ecofys (2010), we assume a linear relationship between efficiency losses and the incorporation rate.[12] This only affects estimations in the *min case* ($\rho_{ToP} = 0$ in the *max case*), in which efficiency losses are to be small because of the 5% incorporation rate. Indeed, several studies have reported very few efficiency losses (or even none) for incorporation rates of about 5–10% (Baxter, 2005; Ecofys, 2010; IEA-IRENA, 2013). Using this setting, we get higher efficiency losses for higher loss coefficients, and, for a given loss coefficient, higher efficiency losses when the incorporation rate increases. As an illustration, let us assume a co-firing situation with the following values: $\eta_c^{nocf} = 0.38$, $\rho_b = 0.05$, and $inc_{c,b} = 0.05$. In this case we get $\eta_c^{cf} = 0.378$, which corresponds to a loss in conversion efficiency of 0.66%. Baxter (2005) indicates that, if all the efficiency losses associated with co-firing were allocated to the biomass fraction of input, they would represent a 0–10% loss in conversion efficiency. In our case, assuming $\rho_b = 0.05$, the loss in conversion efficiency ranges from 0.66% ($inc_{c,b} = 0.05$) to 6.58% ($inc_{c,b} = 0.5$).

2.3. Estimation method for biomass and carbon switching prices

We briefly present the economic background in which situates this analysis. This provides readers with an overview of the literature on which our methodology relies. Next, the analytical framework is introduced.

2.3.1. Switching prices and co-firing: economic background

The usual subject matter of switching prices in electricity is to describe the power producers' ability to substitute (cleaner) gas plants for (dirtier) coal plants, thereby reducing CO_2 emissions. This is known as *fuel switching* and it has generated a wide literature (*e.g.*, Sijm et al., 2005; Kanen, 2006; Delarue and D'haeseleer, 2007, 2008; Carmona et al., 2009; Bertrand, 2010, 2012, 2013; Delarue et al., 2010; Lujan et al., 2012).[13] The basic idea is that with a high enough CO_2 price, coal plants switch places with gas plants in the merit order, which is the ranking of all power plants of a given park by marginal cost of electricity production (*i.e.*, technologies are stacked in order of increasing marginal cost, so that power producers add increasingly expensive plants to production as demand increases). Without a CO_2 price, coal plants are usually brought on line first, because of their lower fuel cost. Gas plants are used next, for shorter periods, when electricity demand increases. However, with a high enough CO_2 price, gas plants may be preferable to coal plants, due to their lower carbon intensity, and thus it may be more profitable to switch from coal to gas plants. If such switching occurs, CO_2 emissions are reduced because coal plants are brought on line for shorter periods. In this case, the CO_2 price that makes fuel switching profitable is known as the *fuel switching price*. It is computed by equalizing the marginal cost of coal and gas plants, including the cost of CO_2. This allows the breakeven points to be determined, which express how advantageous fuel switching is, given the fuel and CO_2 prices.

Relying on this literature, we propose an original method that enables us to derive expressions of the biomass and CO_2 switching prices that make biomass co-firing profitable in various types of coal plants: *carbon switching price* and *biomass switching price*. They correspond to carbon and biomass prices that make coal plants equally attractive under co-firing or classical conditions (*i.e.*, when coal is the only input). The carbon switching price is the carbon price above which it becomes profitable to include biomass in coal plants (*i.e.*, if the actual carbon price is higher than the carbon switching price, co-firing is profitable). The biomass switching price is the biomass price beyond which including biomass in coal plants is no longer profitable (*i.e.*, if the actual biomass price is lower than the biomass switching price, co-firing is profitable).

(*footnote continued*)
account the effects of efficiency losses related to the incorporation rate and the biomass quality (see equation for η_c^{cf} in Table 2).

[12] Whereas some studies find a linear relationship between these variables (*e.g.*, Ecofys, 2010), others report non-linear relationship (*e.g.*, Mann and Spath, 2001). This probably deserves further investigations.

[13] See Bertrand (2011) for a review of this literature.

2.3.2. Estimation method

The first step consists in determining expressions for the marginal cost of electricity, with and without co-firing. Next, the *carbon switching price* and the *biomass switching price* can be derived by equalizing these expressions.

First of all, the marginal cost of electricity on the fuel and CO_2 prices. In this way, the coal and biomass types impact the marginal cost of co-fired electricity. Indeed, the price of lignite is different from that of hard-coal. Likewise, the price of biomass varies from one quality to another. The marginal cost of co-fired electricity also depends on the changing combustion behavior of the coal-fired station, due to adding biomass in the boiler. More specifically, biomass may induce slight losses in the conversion efficiency of coal plants. In order to account for this, we model the efficiency rate (MWh_{elec}/MWh_{prim}) of coal plants c under co-firing using the equation for η_c^{cf}, as given in Table 2. Then, the higher the loss coefficient (ρ_b) is, the higher the efficiency loss. This increases the cost of co-firing. Furthermore, modifying the incorporation rate also affects efficiency losses and the cost of co-firing. This is accounted for with the influence of $inc_{c,b}$ on η_c^{cf}.[14]

2.3.3. Marginal cost of electricity under co-firing

Using the equation for η_c^{cf} given in Table 2, we can express the marginal cost of one MWh_{elec} generated in coal plants c under co-firing. We get

$$MC_c^{cf} = q_{c,c}^{cf} C_c + q_{c,b}^{cf} B_b + e_c^{cf} EUA, \tag{1}$$

where B_b is the price of biomass b ($Euros/MWh_{prim}$) and C_c is the price of coal c ($Euros/MWh_{prim}$), with $c = \{HC\ (Hard\text{-}Coal),\ L\ (Lignite)\}$. EUA ($Euros/tCO_2$) denotes the price of European Union Allowances from the EU ETS.

$h_c^{cf} = 1/\eta_c^{cf}$ is the heating rate (MWh_{prim}/MWh_{elec}) of coal plants c under co-firing. It is computed given η_c^{cf} (Table 2). h_c^{cf} corresponds to the quantity of primary energy (MWh_{prim}) in the biomass-coal blend which allows generating one MWh of electricity in coal plants c under co-firing. Hence, once h_c^{cf} and $inc_{c,b}$ are known, one can compute the quantities of coal and biomass needed to generate one MWh of co-fired electricity: $q_{c,b}^{cf} = inc_{c,b} h_c^{cf}$ and $q_{c,c}^{cf} = (1 - inc_{c,b})\, h_c^{cf}$. $q_{c,b}^{cf}$ ($q_{c,c}^{cf}$, respectively) denotes the quantity of biomass b (quantity of coal c, respectively) in the biomass-coal blend h_c^{cf}, with $h_c^{cf} = q_{c,c}^{cf} + q_{c,b}^{cf}$.

Finally, $e_c^{cf} = e_c q_{c,c}^{cf}$ is the emission factor of coal plants c under co-firing (tCO_2/MWh_{elec}). It is computed given e_c, the primary energy emission factor of coal c (tCO_2/MWh_{prim}). In the equation we use for e_c^{cf}, emissions arise from the coal fraction of energy input only. This reflects the zero emission rate applied to biomass in the EU ETS.

2.3.4. Marginal cost of electricity without co-firing

Under a classical cycle, when coal is the only input, we define the marginal cost of one MWh_{elec} generated in coal plants c as follows:

$$MC_c^{nocf} = h_c^{nocf} C_c + e_c^{nocf} EUA, \tag{2}$$

where $h_c^{nocf} = 1/\eta_c^{nocf}$ and $e_c^{nocf} = e_c h_c^{nocf}$ are, respectively, the heating rate (MWh_{prim}/MWh_{elec}) and the emission factor (tCO_2/MWh_{elec}) of coal plants c without co-firing. η_c^{nocf} and e_c represent, respectively, the efficiency rate of coal plants c without co-firing (MWh_{elec}/MWh_{prim}), and the primary energy emission factor of coal c (tCO_2/MWh_{prim}). Note that Eq. (1) is equivalent to Eq. (2) when $inc_{c,b} = 0$ and $\rho_b = 0$,

2.3.5. Biomass and carbon switching prices

Equalizing Eqs. (1) and (2), we get

$$EUA_{c,b}^{SW} = \frac{q_{c,b}^{cf} B_b - (h_c^{nocf} - q_{c,c}^{cf}) C_c}{e_c^{nocf} - e_c^{cf}} \quad \text{and}$$
$$B_c^{SW} = \frac{C_c (h_c^{nocf} - q_{c,c}^{cf}) + EUA(e_c^{nocf} - e_c^{cf})}{q_{c,b}^{cf}}, \tag{3}$$

where $EUA_{c,b}^{SW}$ is the *carbon switching price* ($Euros/tCO_2$) associated with using biomass b in coal plants c, and B_c^{SW} is the *biomass switching price* ($Euros/MWh_{prim}$) associated with using biomass in coal plants c.

$EUA_{c,b}^{SW}$ is calculated given the prices of biomass b and coal c. It corresponds to the increased fuel cost of co-firing that enables power producers to abate one ton of CO_2.[15] Accordingly, co-firing is cheaper than using coal plants in the classical cycle if the additional fuel cost associated with co-firing ($q_{c,b}^{cf} B_b - (h_c^{nocf} - q_{c,c}^{cf}) C_c$) is lower than the cost of increased CO_2 emissions in the case of the classical cycle ($EUA(e_c^{nocf} - e_c^{cf})$). In other words, switching to co-firing will (will not, *respectively*) occur if $EUA_{c,b}^{SW} < EUA$ ($EUA_{c,b}^{SW} > EUA$, *respectively*), where EUA denotes the observed EUA price.

B_c^{SW} is calculated given the prices of coal c and of EUA. It corresponds to the benefit associated with including one MWh_{prim} of biomass in coal plants of type c. This arises from reduced costs of coal consumption ($C_c(h_c^{nocf} - q_{c,c}^{cf})$) and of CO_2 emissions ($EUA(e_c^{nocf} - e_c^{cf})$). Hence, B_c^{SW} can be considered as the benefit of one MWh_{prim} of biomass in coal plants c, whereas B_b (the observed price of biomass b) is the cost. Therefore, including biomass b in coal plants c is a profitable (not profitable, respectively) option as long as $B_b < B_c^{SW}$ ($B_b > B_c^{SW}$, respectively).

As an illustration, Figs. 3 and 4 show the changes in biomass and carbon switching prices using market price data for wood pellets (Ice-Endex), EUA (Ice) and hard-coal (OTC index, McCloskey) for the period 2008–2013. Moreover, in order to consider further situations, we build a series of prices reflecting biomass that has not been pre-treated (*e.g.*, agricultural residues or wood chips), assuming that the price of pre-treated biomass is about twice that of raw biomass (and that the price of raw biomass is perfectly correlated with the market price for wood pellets).

Figs. 2 and 3 show that, when considering wood pellets, switching to co-firing is never a profitable option. Even though efficiency losses are smaller in this case, the price of wood pellets is so high that we never observe $EUA^{SW} < EUA$ and $B^{SW} > B$. By contrast, using the constructed price series for raw biomass, we observe that switching to co-firing was often profitable in 2010 and 2011.

Note here that co-firing may provide hedging against price volatility, which is an interesting outcome for power producers. Biomass can be viewed as an opportunity fuel that is only used when prices are favorable. Hence, as they can then still rely on the use of coal, power producers can manage temporary disturbances on the biomass, coal, or carbon markets, by adapting the share of biomass in the blend. This makes it possible to reduce the risk associated with volatility of prices.

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[14] The loss coefficient and the incorporation rate depend on the type of biomass. This is because losses in conversion efficiency tend to increase when the biomass quality decreases. In the same way, the higher the quality of biomass is, the higher the possible incorporation rate is. Accordingly, the loss coefficient and the incorporation rate are assumed to vary with the biomass quality.

[15] As opposed to fuel switching with coal and gas plants, co-firing does not necessarily entail changes in the dispatch of power plants. More specifically, if co-firing does not modify the merit order of power plants, there is no change in the dispatch. In this case, the constraints associated with co-firing are less stringent, which tends to reduce the cost of managing power generation to reducing CO_2 emissions.

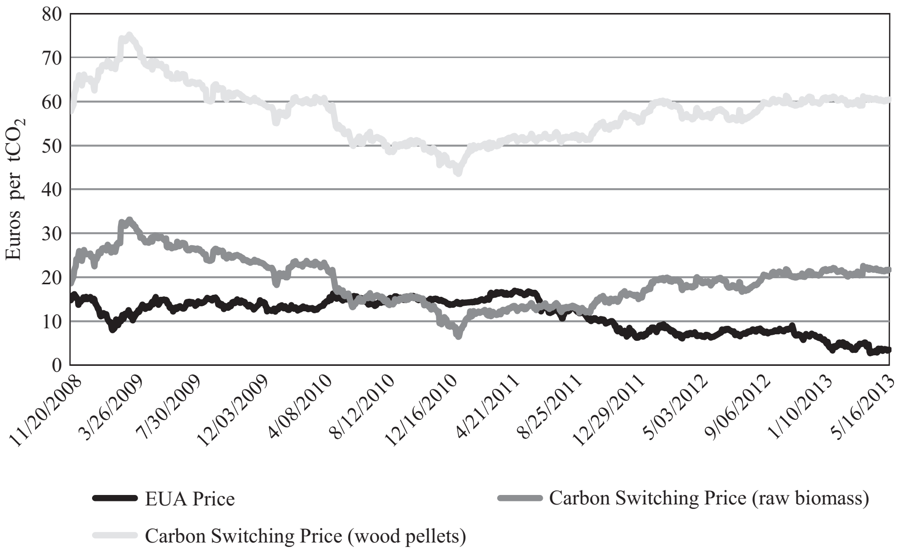

Fig. 2. EUA price and carbon switching prices for wood pellets and raw biomass. The carbon switching price have been computed assuming hard-coal power plants with a 38% efficiency rate, an emission factor of 0.339 (tCO_2/MWh_{prim}) for hard-coal, a 10% incorporation rate, and losses coefficients of 0.01 and 0.05 for wood pellets and raw biomass, respectively.

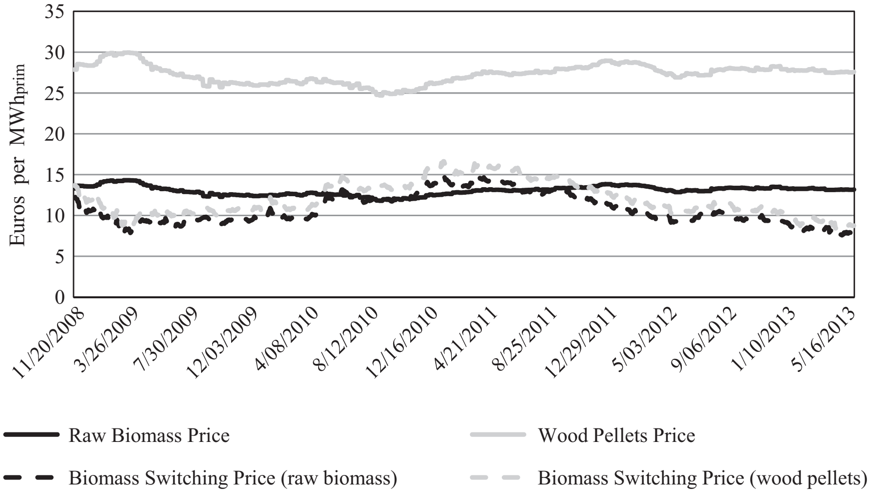

Fig. 3. Biomass prices and biomass switching prices for wood pellets and raw biomass. The biomass switching price have been computed assuming hard-coal power plants with a 38% efficiency rate, an emission factor of 0.339 (tCO_2/MWh_{prim}) for hard-coal, a 10% incorporation rate, and losses coefficients of 0.01 and 0.05 for wood pellets and raw biomass, respectively.

3. Results

3.1. Results for potential biomass demand and CO_2 abatements

We use 2011 yearly power production data of hard-coal, lignite, and dedicated biomass power plants in the EU-27. Data are provided by ENTSO-E, the European Network of Transmission System Operators for Electricity. We assume efficiency rates of 30, 34, and 38%, for dedicated biomass, lignite, and hard-coal power plants, respectively.[16] The CO_2 emission factors for primary energy (tCO_2/MWh_{prim}) are provided by IPCC (2006): 0.357 for lignite, 0.339 for hard-coal, and zero for biomass.

Results indicate that the EU potential biomass demand ranges from 1344 to 4739 PJ a year (381–3787 for co-firing alone).[17] In all cases, Germany has the highest potential demand with 498–1618 PJ (125–1243, co-firing alone). This is much higher than Poland, the country with second biggest demand potential with 132–738 PJ (68 to 675, co-firing alone). Moving from the min to the max case, we observe a change in the distribution of quantities among countries. The demand share from coal plants rises while that of dedicated biomass plants falls (Figs. 5 and 6). Hence, the proportion of countries with many coal-fired plants and few dedicated biomass plants in their power mix increases (*e.g.*, Poland and UK, Fig. 4). On the other hand, countries with many dedicated biomass plants and few coal plants represent a smaller share of the whole EU demand (*e.g.*, Finland and Sweden, Fig. 4). In between,

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[16] We consider both co-firing in hard-coal and lignite plants in our estimations. Indeed, the co-firing potential of hard-coal and lignite plants is broadly the same. Slight differences may occur in certain cases, because hard-coal plants generally require high-quality biomass, whereas lignite plants can more easily burn biomass with high moisture content. See ECF (2010).

[17] Assuming incorporation rates ranging from 10% to 15% (on energy basis), Hansson et al. (2009) find a potential biomass demand from co-firing of approximately 500–900 PJ per year in the EU-27.Note that we use power generation data for 2011, whereas Hansson et al. (2009) use data from 2004.

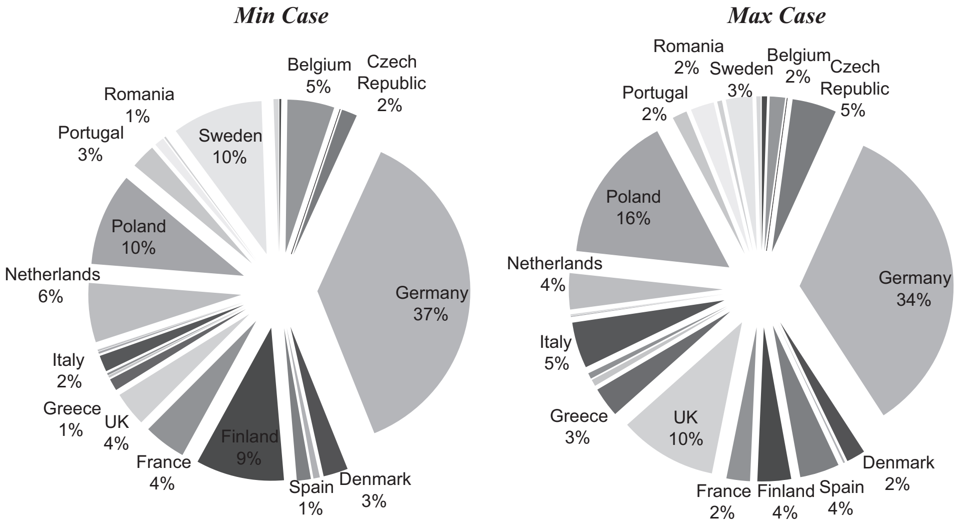

Fig. 4. The EU countries' shares in the total EU potential biomass demand from the power sector (co-firing+dedicated biomass plants).

the share of Germany is high and stable in all cases, because the country has both many coal and dedicated biomass plants.

Regarding CO_2 abatements, results indicate that the total EU potential ranges from 31.6 to 364.6 Mt a year.[18] Here again, Germany has the highest share with 10.4–120.8 Mt. Poland and the UK also have great potential, due to the scale of coal-based electricity in these countries.[19] As opposed to what we observe with biomass quantities, there is no change in the geographical distribution of abatements when we move from the min to the max case (Fig. 7). Indeed, the contribution of each type of coal plant to abatements remains unchanged when the incorporation rate increases (Figs. 8 and 9), whereas we observe a reduced share for the potential demand of dedicated biomass power plants (Figs. 5 and 6). When the incorporation rate increases, this translates into the same percentage of increase in every coal plant, whatever the country and the type of coal. Hence, only the abatement volumes are increased, and the distribution remains stable.

3.2. *Results for biomass and carbon switching prices*

In order to compute the biomass and carbon switching prices, we use price data for lignite, hard-coal, and different types of biomasses. For simplicity, we assume annual prices in our estimations. Values and references are summarized in Table 4. Efficiency rates of coal plants and emission factors for primary energy are the same as in Section 3.1.

In all calculations, we assume a 10% incorporation rate. As already indicated, this corresponds to values encountered in practice.[20] We split the different types of biomasses Table 4 into two categories: Pre-Treatment (PT), and No Pre-Treatment (NOPT). We apply a higher loss coefficient to NOPT, reflecting a lower biomass quality (Table 5). As high quality of biomass, ToP and WP are included in PT, while AR and WC are in NOPT. We choose this division because WC exhibits energy contents that are quite similar to those for raw wood (Maciejewska et al., 2006; Acharya et al., 2012).

So far we have defined the carbon switching price as the increased fuel cost of co-firing, which enables one ton of CO_2 to be abated. However, more specifically, two effects have to be considered. On the one hand, the fuel cost of biomass ($q^{cf}_{c,b}B_b$) rises (since no biomass was used before). On the other hand, the cost of coal consumption ($(h^{nocf}_c - q^{cf}_{c,c})C_c$) falls. Thus, defining $EUA^{SW}_{c,b}$ as an increased fuel cost is equivalent to considering that the effect of biomass is greater than that of coal. It is worthwhile mentioning these two effects in order to interpret the results of Table 5.

Table 5 shows that the $EUA^{SW}_{c,b}$ associated with lignite is invariably cheaper than that of hard-coal, whatever the situation we consider. This is because the lignite price is higher than the hard-coal price in our data. Thus, whenever a MWh_{prim} of biomass is included in a coal plant, it comes with a higher avoided cost for coal consumption in the case of lignite. This translates into a lower $EUA^{SW}_{c,b}$ in lignite plants, meaning that switching to co-firing is cheaper and profitable with lower CO_2 prices in this case. This result can also be explained by the higher emission factor of lignite, which implies that more abatements result from substituting one MWh_{prim} of biomass for one MWh_{prim} of coal, in the case of lignite. Thus, compared with hard-coal, less biomass needs to be substituted for lignite in order to abate one ton of CO_2. This tends to decrease the $EUA^{SW}_{c,b}$ of lignite compared with that of hard-coal.

Table 5 also shows that the $EUA^{SW}_{c,b}$ associated with non pre-treated biomass (WC and AR) is cheaper than that of pre-treated biomass (ToP and WP). It is explained by the price difference between pre-treated and non pre-treated biomass. The pre-treated biomass is so expensive in our data that it is associated with a higher $EUA^{SW}_{c,b}$ than for non pre-treated biomass, even taking into account the lower loss coefficient of pre-treated biomass.[21] An exception arises with the $EUA^{SW}_{c,b}$ values associated with the

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[18] This corresponds to between 0.7% and 7.7% of the EU GHG emissions in 2010, which accounted for 4721 $MtCO_2e$ (EEA, 2012). In comparison, coal-to-gas fuel switching, which is often considered as one of the main abatement options in the EU ETS, offers a maximal potential of about 150 $MtCO_2$ a year (Delarue et al., 2012). See also Solier (2013) on this topic.

[19] Assuming incorporation rates around 10% (on energy basis), Berggren et al. (2008) find that about 4 Mt of CO_2 per year can be abated through co-firing with biomass in Polish coal plants. We find that about 5 Mt of CO_2 per year can be abated through co-firing when a 5% incorporation rate is assumed. This difference in results may be explained by the data. Indeed, we use data reflecting power generation in 2011, whereas Berggren et al. (2008) use data from 2004.

[20] Whereas the effect of modifying the loss coefficient is straightforward, it is difficult to disentangle in the case of the incorporation rate. In fact, we estimated that modifying the incorporation rate induces two contrasting effects for the co-firing cost, and the net effect is undetermined for the carbon and biomass switching prices. Results are available from the authors upon request.

[21] Results of Table 5 indicate that the carbon switching price is an increasing function of the loss coefficient. That is, the higher the loss coefficient, the higher the

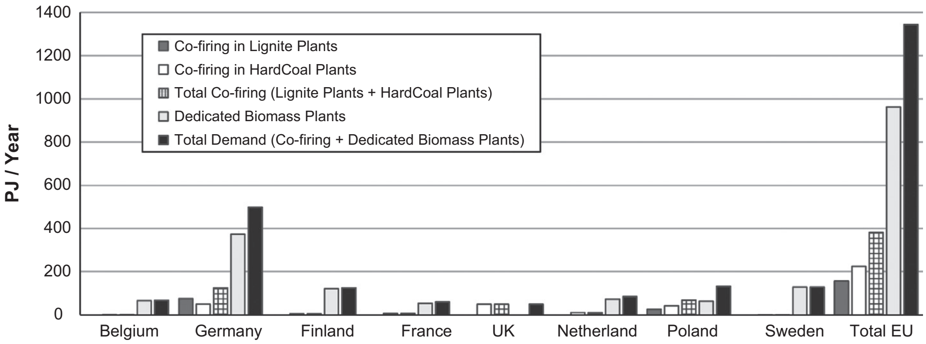

Fig. 5. Potential biomass demand (per country and type of power plant) in the min case.

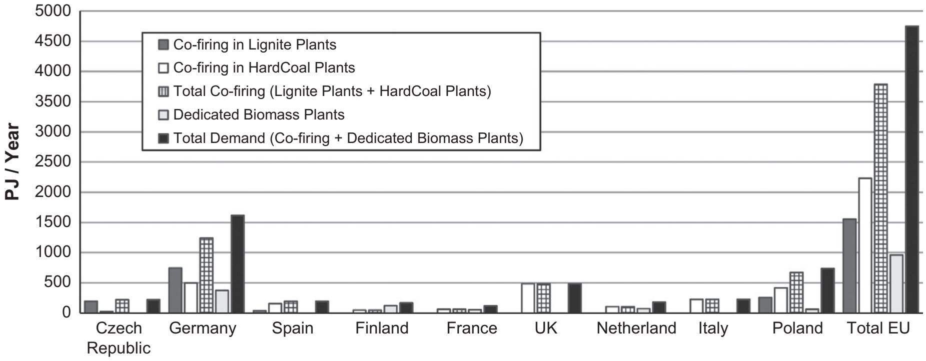

Fig. 6. Potential biomass demand (per country and type of power plant) in the max case.

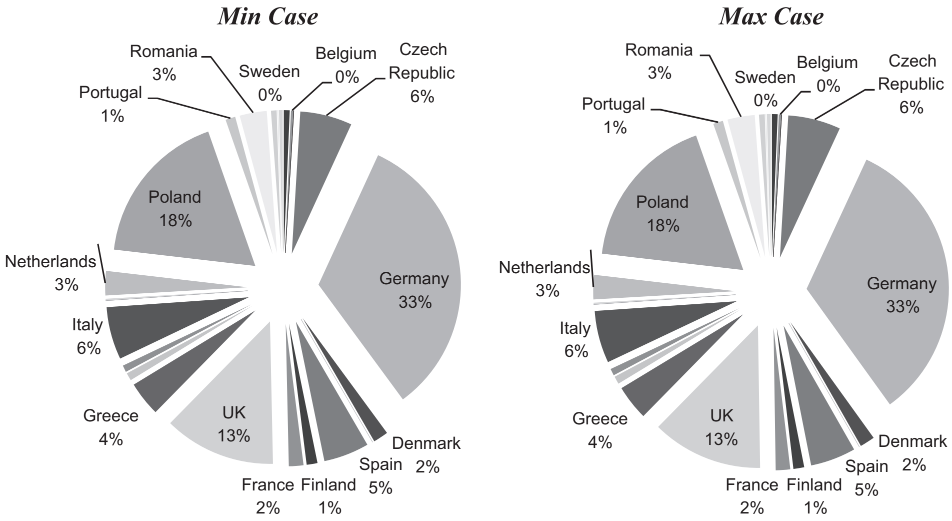

Fig. 7. EU countries' shares in the total EU abatement potential from co-firing (hard coal + lignite).

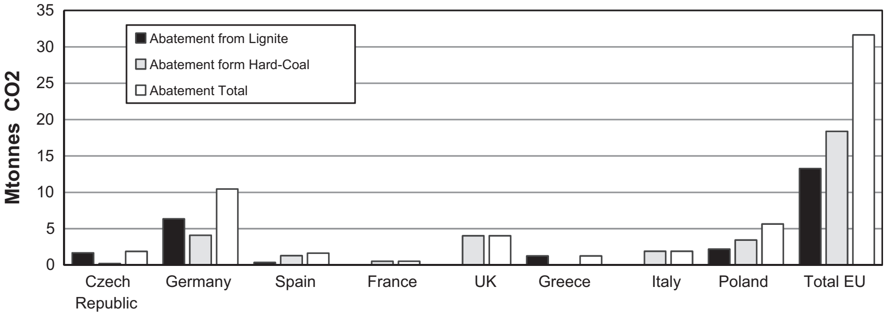

Fig. 8. Estimated CO_2 abatements (per country and type of power plant) in the min case.

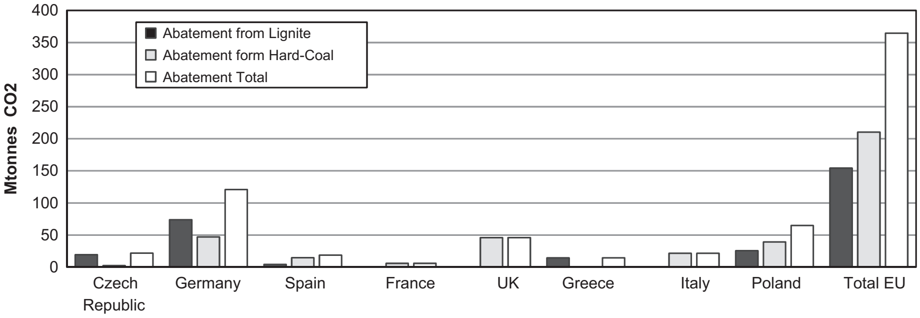

Fig. 9. Estimated CO_2 abatements (per country and type of power plant) in the max case.

Table 4
Fuel prices (Euro/MWh_{prim}) as delivered to power plants.

Fuel	Prices – Euros/ MWh_{prim} (as delivered to power plants)	Sources
Lignite	16.8	www.kohlenstatistik.de
Hard coal	11.3s	www.kohlenstatistik.de
Torrefied pellets (ToP)	30–31.7	ECF (2010), KEMA (2012)
Wood pellets (WP)	25–31	ECF (2010), Argus (2011), KEMA (2012)
Wood Chips (WC)	13.4–27	ECF (2010), Argus (2011)
Agricultural Residues (AR)	13–16	ECF (2010)

Table 5
Estimated carbon switching prices (using price data from Table 2) as given by Eq. (3).

$EUA^{SW}_{c,b}$	**Pre-Treatment** ($\rho_{PT}=0$)		**No Pre-Treatment** ($\rho_{NOPT}=0.05$)	
	Low biomass price	High biomass price	Low biomass price	High biomass price
$EUA^{SW}_{L,ToP}$	36.88	41.64	(51.36)[a]	(53.66)[a]
$EUA^{SW}_{HC,ToP}$	55.11	60.12	(68.51)[a]	(70.89)[a]
$EUA^{SW}_{L,WP}$	22.88	39.68	(34.35)[a]	(54.65)[a]
$EUA^{SW}_{HC,WP}$	40.38	58.06	(51.54)[a]	(71.90)[a]
$EUA^{SW}_{L,WC}$	(−9.60)[a]	(28.48)[a]	−3.13	41.51
$EUA^{SW}_{HC,WC}$	(6.19)[a]	(46.27)[a]	12.17	58.33
$EUA^{SW}_{L,AR}$	(−10.44)[a]	(−2.32)[a]	−4.44	5.40
$EUA^{SW}_{HC,AR}$	(5.01)[a]	(13.85)[a]	10.81	21.00

[a] Values associated with losses coefficients which do not reflect the quality of the considered biomass type.

high WC price, which are higher than those associated with the high WP price. In this case, the price difference of biomass is so small that it produces a weaker effect than the difference in loss coefficients.

Interestingly, Table 5 shows that the $EUA^{SW}_{c,b}$ of lignite plants turns out to be negative in several cases, meaning that switching to co-firing is a profitable option even for a zero CO_2 price. The negative $EUA^{SW}_{c,b}$ values arise from circumstances in which the biomass type considered is so cheap that, combined with the high lignite price, this translates into situations where the additional cost of biomass under co-firing is lower than the coal cost saving. Hence, power producers can make money by switching to co-firing, even ignoring the CO_2 cost saving.

Table 6 also indicates that co-firing is cheaper in lignite plants. Indeed, we observe a higher B^{SW}_{c} in the case of co-firing in lignite plants. This reflects the greater benefits associated with including one MWh_{prim} of biomass in lignite plants, due to greater coal cost savings with a higher lignite price. Accordingly, the range over which biomass prices are compatible with profitable co-firing is larger with lignite than with hard-coal. For instance, assuming non pre-treated biomass with a Euros 5 CO_2 price, results indicate that co-firing in lignite plants is a profitable option as long as the biomass price is not more than Euros 18.61. The same breakeven value is Euros 13 with hard-coal plants. Hence, with a biomass price of Euros 15 per MWh_{prim}, it would be profitable to switch to co-firing in lignite plants, but not to hard-coal plants.

We also observe in Table 6 that B^{SW}_{c} invariably has a higher value when reflecting pre-treatment. This is explained by the lower loss coefficient we use in this case. This translates into lower losses in conversion efficiency, and thus lower cost for co-fired electricity. Consequently, co-firing produces better outcomes in this case, which appears in the higher B^{SW}_{c}.

Finally, Table 6 illustrates that co-firing can remain profitable with a very high biomass price, if the carbon price is high enough. For instance, assuming a Euros 50 CO_2 price, co-firing would be profitable with a biomass price of about Euros 25–35 per MWh_{prim} (Euros 40–50 per MWh_{prim} with a Euros 100 CO_2 price), depending on the situation. Hence, the carbon price can be an important driver of co-firing, which can make switching profitable even with a very high biomass price.

4. Discussion

In order to put our results into perspective, we match the potential biomass demand from our estimations with potential biomass supply in Europe. By comparing potential supply and demand, we want to shed light on how the biomass market may be impacted by demand from the electricity sector.

In order to figure out what the potential biomass feedstocks are, we rely on the literature estimating biomass resources in Europe. We identify three main references that provide an extensive overview of potential biomass supply for energy in the EU-27: Ericsson and Nilsson (2006), Renew (2006), and Panoutsou et al. (2009).[22] Renew (2006) provides estimates for 2020 with high (S1) and low (S2) biomass production. Starting Point reflects the years 2000–2004. In Ericsson and Nilsson (2006), scenarios 1, 2, and 3 refer to the periods 2015–2025, 2025–2045, and beyond

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(*footnote continued*)
loss in conversion efficiency. This tends to increase the additional fuel cost needed to abate one ton of CO_2 under co-firing, and thus the carbon switching price.

[22] These papers are based on a large number of studies using data from country level reports and European statistics. This provides us with a wide overview of the potential biomass supply in the EU countries.

Table 6
Estimated biomass switching prices (using price data from Table 2) as given by Eq. (3). Subscripts PT and NOPT only reflect different values of losses coefficient (as given in Table 3).

$B^{SW}_{c,b}$	Carbon price				
	Euros 5/tCO_2	Euros 10/tCO_2	Euros 20/tCO_2	Euros 50/tCO_2	Euros 100/tCO_2
$B^{SW}_{L,NOPT}$	15.88	17.40	20.45	29.58	44.81
$B^{SW}_{HC,NOPT}$	11.29	12.76	15.71	24.54	39.28
$B^{SW}_{L,PT}$	18.61	20.40	23.97	34.68	52.54
$B^{SW}_{HC,PT}$	13.00	14.69	18.09	28.55	45.23

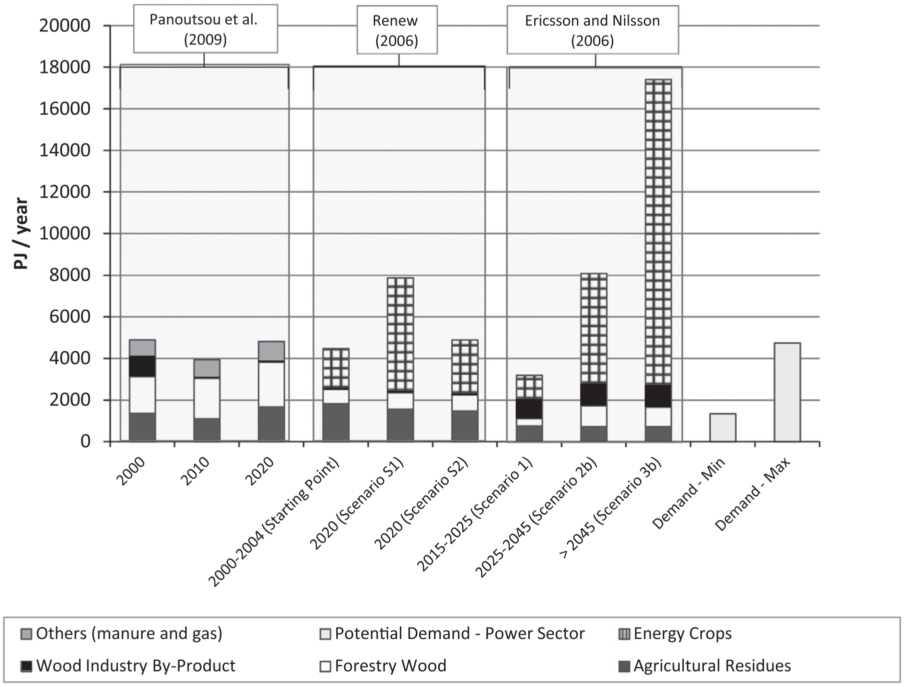

Fig. 10. Potential biomass supply assessment in EU-27.

2045, respectively. The letters in the scenario names indicate low (a) and high (b) biomass supply. Panoutsou et al. (2009) provide estimates for 2000, 2010, and 2020.

According to the above papers (that use basically the same classification for biomass resources), we consider four representative biomass groups as follows:

- *Agricultural residues*, which include materials produced along with crops (*e.g.*, straw, fruit tree prunings, corn stems, etc).
- *Forestry wood*, which includes wood fuel and residues from logging and forest thinning (*e.g.*, branches, sawdust, stumps and roots, etc).
- *Wood industry by-products*, which include residues that are produced in forest-related industries (*e.g.*, sawdust, husks, scrap wood, etc).
- *Energy crops*. Woody or herbaceous crops that are grown specifically for their fuel value. This includes short rotation (*e.g.*, willow, poplar, eucalyptus) and perennial crops (*e.g.*, miscanthus, switchgrass, reed canary grass).

Fig. 10 shows different biomass supply scenarios from the aforementioned papers, for five time horizons (2000, 2010, 2020, 2025–2045, and beyond 2045). Thus, we obtain a set of biomass supply potentials, which are compared to the potential demand in the power sector from our estimations.

Fig. 10 indicates that there may be stark differences from one study to another. For instance, considering forestry wood, agricultural residues, and wood-industry by-products for 2020, the estimated resource varies from 2000 (Ericsson and Nilsson, 2006) or 2350 (Renew, 2006) to almost 4000 PJ a year (Panoutsou et al., 2009). There may also be significant differences in the same study, when considering different scenarios. For instance, Renew (2006) estimates an overall potential for 2020 varying from 4900 to almost 8000 PJ a year, depending on the scenario. This uncertainty about the actual biomass supply mainly reflects uncertainties about agronomic and weather conditions or land availability for energy crops.

Indeed, there is much uncertainty about the share energy corps will represent in the future. Availability of agricultural land in the future, potential detrimental effects related to changes in land-use, or reduced biodiversity may constitute barriers to their development.[23] The evolution of yields is also an important unknown parameter. Even though yields have increased in Europe during

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[23] See Ben Fradj (2013) for an economic analysis of potential effects induced by changes in land-uses due to the development of energy crops in France.

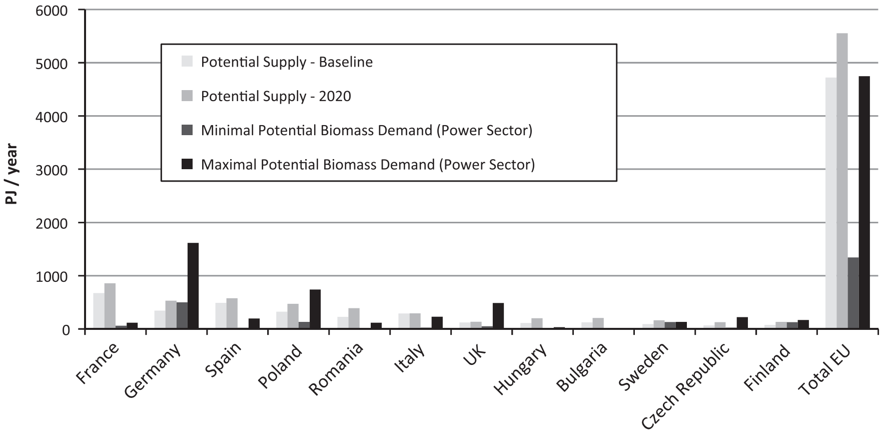

Fig. 11. Comparison between potential biomass supply and demand in the ten EU countries with the highest potential supply.

recent decades, we cannot be sure that this rise will continue at the same rate in the future. Renew (2006) anticipates an increase in yields from 10 to 30% by 2020 in their intensive production scenario, and from 7% to 20% in another scenario in which agricultural practices are less intensive. The share of energy crops also differs from one scenario to another.

Results also depend on hypotheses about availability factors of biomass for energy purposes. Even though the same availability factors are assumed in general for all the European countries, the value can differ from one study to another. For example, Panoutsou et al. (2009) retain a uniform availability factor of 30% for agricultural residues in all the European countries. Ericsson and Nilsson (2006) and Renew (2006) distinguish between the availability factor of maize (25%) and other cereals (22%).

The heterogeneity of hypotheses induces significant differences in the share of each biomass source in the overall biomass supply (Fig. 10). Globally, the literature indicates that energy crops offer the most important potential source of biomass supply, with 1150–14,000 PJ a year. The next category may be forestry, wood industry, or agricultural residues, depending on the scenario and hypotheses.

Despite uncertainties on the supply side, when comparing the EU biomass supply from the literature with potential biomass demand from the power sector, we observe that demand may be quite high compared with supply and sometimes outstrip it (Figs. 10 and 11).[24] This may induce potential tensions in the biomass market.

Actually, our results indicate that the EU-27 potential demand could cover between 8% (min potential demand under Ericsson and Nilsson's (2006) Scenario 3b) and 148% (max potential demand under Ericsson and Nilsson's (2006) Scenario 1) of biomass production in Europe.[25] Thus, if the actual demand from electricity turns to be close to the upper bound (*i.e.*, 148% of the potential supply), one may conjecture that this would significantly affect the biomass price.[26] As pointed out in Section 3.2, depending on the situation, co-firing is profitable with a biomass price of 16–24 (25–35, respectively) Euros per MWh_{prim}, when the carbon price is 20 (50, respectively) Euros per ton. With a Euros 100 carbon price, co-firing is profitable with a biomass price of about 40–50 Euros per MWh_{prim}. Hence, if the carbon price is high enough, high biomass prices can be affordable in the power sector, whereas this may be a barrier for other competing biomass usages.

When comparing situations in various EU countries, we observe great differences in the balance between potential demand and supply (Fig. 11). While some countries have a heavily positive balance (*e.g.*, France, Spain), meaning that they can produce more than the potential demand from inland power generation, others countries have a significantly negative balance (*e.g.*, Germany, UK). This indicates that substantial trading opportunities may exist among EU countries, in which some countries with large positive balance may become net suppliers.[27] While, feedstock costs are usually low for biomass, additional costs related to logistics and transportation may be much more significant (Hamelinck et al., 2005). However, applying pretreatments to raw biomass would aim to save transport and handling costs, which would facilitate biomass trading among European countries and beyond.

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[24] In Fig. 11, the Baseline Supply Potential refers to the average of values provided in Renew's (2006) Starting Point and in Panoutsou et al.'s (2009) EP 2000. The 2020 Supply Potential is the average of values in Renew's (2006) S1 and S2, Ericsson and Nilsson's (2006) scenasrio 1, and Panoutsou et al.'s (2009) EP 2020.

[25] Note that we used 2011 data to estimate potential demand from the power sector. Thus projected potential demand for 2020 would be substantially higher than our estimates, if considering investments in new power plants using biomass. Those investments would be supported by the different European schemes to promote biomass in energy. For co-firing, investments in new highly efficient coal plants would be triggered by Carbon Capture and Storage (CCS) technologies, which may result in negative CO_2 emissions (*i.e.*, net removal of CO_2 from the atmosphere) when associated with biomass (IEA-IRENA, 2013).

[26] A range of papers have investigated the impact of resource scarcity on the biomass price (*e.g.*, De Wit and Faaij, 2010; Van Dam et al., 2007; Hoogwijk et al., 2009; Caurla, 2012). Those studies rely on simulations that investigate the link between harvesting cost and production level for different biomass resources such as wood and agricultural residues. Their results demonstrate that costs rise when the level of production increases, since this implies collecting resources that are increasingly difficult to access (which increases transport and on-site collection costs). As a consequence, the price of biomass increases. On the other hand, exploitation of those resources might be motivated by high biomass prices resulting from high biomass demand (Parrika, 2004).

[27] Remember that we refer to potential quantities given by certain technical characteristics. Thus, the quantities do not necessarily reflect current practices. For example, a country with a positive balance in our estimations (*i.e.* potential supply greater than potential demand) may be an importer of biomass in practice. In this case, the positive balance suggests that a lot of potential biomass resources are currently not exploited in this country (*e.g.*, some woody biomass that is difficult to access at a competitive cost), which explains imports. However, taking into account the whole potential biomass resources, including the non-exploited ones, the potential supply exceeds the needs, which results in a positive balance. In this case, if the non-exploited resources turn out to be exploited (which obviously depends on the biomass price), this would reduce imports and/or increase exports for this country.

5. Conclusions and policy implications

This paper provides estimations of the potential biomass demand from the existing power plants in the European power sector, considering both biomass co-firing in coal plants and dedicated biomass power plants. Furthermore, we match our estimates with the potential biomass supply in the EU-27, and we compute the CO_2 abatements associated with co-firing opportunities. We also investigate the cost of biomass co-firing in coal plants, and we derive a method that enables us to compute the biomass and CO_2 breakeven prices for co-firing.

Results indicate that the potential biomass demand from the power sector may be quite high compared with the potential biomass supply (sometimes higher). Co-firing offers the highest potential with up to 80% of the overall potential demand. Co-firing can also produce high volumes of CO_2 abatements, which may account for more than double the abatements from the coal-to-gas fuel switching.

The switching prices analysis indicates that the co-firing profitability depends on the biomass quality and on the type of coal plants involved. In particular, we show that the carbon switching price associated with using biomass in lignite plants is cheaper than that of hard-coal plants. Likewise, we find that the biomass switching price has higher values when associated with lignite plants. This reflects the greater benefits associated with including biomass in lignite plants, due to greater coal cost savings (with higher lignite prices) and more abatement.

Overall, our results indicate that the potential biomass demand from the European power sector could cover between 8% and 148% of the biomass production in Europe. Thus, if a high share of the potential demand turns out to be economically profitable, this may raise biomass prices and result in conflicts between different biomass usages. Interestingly, we also find that most of the biomass-based electricity remains profitable at very high biomass prices, when the carbon price is high enough. This provides insight into how the biomass market is impacted by the EU ETS and other climate policies, which is a highly relevant issue for policy-makers, researchers, and practitioners in fields of energy, forestry, agriculture, and climate.

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